STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-580

March 26, 2001

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Central Maine Power Company's Revenue Requirements and Rate Design

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

By this Order, we reduce Central Maine Power Company's (CMP) transmission and distribution (T&D) rates by 0.8¢/kWh for the T&D customers that fall within the medium and large non-residential standard offer customer classes. We do so to mitigate the impact of significant increases to generation prices, whether from standard offer or competitive providers, that these customers must pay effective March 1, 2001.

II. BACKGROUND

New standard offer arrangements became effective on March 1, 2001 for medium and large non-residential standard offer customers in CMP's service territory. On February 7, 2001, in Docket No. 2000-808, we approved the wholesale supply arrangements so that CMP could serve as the standard offer provider for the medium and large classes. In the February 7 Order, we established the standard offer prices that reflect the costs to CMP of serving as standard offer provider, including the underlying wholesale power supply costs.

The resulting standard offer price for the medium non-residential standard offer customer class of 8.52 cents/kWh reflects an increase of approximately 40% over last year's standard offer price, and the increase in total electricity costs (standard offer plus T&D rates) over last year is 25%. For the large non-residential standard offer customer class, the new standard offer prices reflect an increase of approximately 50% over last year's standard offer prices, and the increase in total electricity costs ranges from 25% to almost 40%.

In addition, we are aware that many of the medium and large customers who are served by competitive providers have retail contracts that terminated on March 1, 2001 or will terminate effective on the next meter read date. Because of current market conditions, customers who are not on standard offer service, but who have a retail supply contract that will soon terminate, will likely face similar price increases in the retail competitive market.

Recognizing the significant impact of these generation price increases, on February 9, 2001, we invited comment from interested persons on whether the Commission should mitigate that impact . The Commission also sought comment on whether mitigation should occur by adjusting standard offer prices, T&D rates or some other method. All Bangor Hydro-Electric (BHE) T&D customers were subject to similar generation price increases and standard offer arrangements that ended on February 28, 2001. Accordingly, we sought comments in our standard offer proceeding, Docket No. 2000-808, as to both CMP and BHE.[1]

The Commission received comments from CMP, BHE, Maine Public Service Company (MPS), Enron Power Marketing, Inc. and Enron Energy Services, Inc. (Enron), Independent Energy Producers of Maine (IEPM), Competitive Energy Services (CES), Energy Atlantic (EA), the Office of the Public Advocate (OPA) and the Industrial Energy Consumer Group (IECG). The commenters generally agreed that mitigation, if it should occur at all, should be implemented through T&D rates and not standard offer prices.

The utilities generally opposed T&D rate reductions to mitigate generation prices on the ground that the asset sale gain accounts are needed to avoid future price increases due to stranded cost recovery. The utilities argued that the accounts should be used only for T&D matters and not to soften the impact of generation prices; restructuring was intended to separate generation from T&D services.

The suppliers generally agreed that, most importantly, the Commission should avoid mitigation of standard offer prices. As to T&D prices, the suppliers' views included opposition (IEPM), neutrality (EA), and support for using CMP's asset sale gain account to provide relief to T&D customers (Enron and CES). Suppliers were generally opposed to the creation of new deferrals of T&D costs to provide rate relief, fearing that the credit worthiness of the utilities could create problems similar to those experienced by California.

Customer representatives advocated lower T&D rates to mitigate the higher generation prices. The OPA proposed a T&D rate reduction of 1¢/kWh. The IECG advocated a 2¢/kWh reduction. In the IECG's view, such a rate reduction would merely recognize a future stranded cost recovery reduction that will result when the entitlements to CMP's non-divested assets are sold into the generation market effective March 1, 2002, pursuant to Chapter 307. Moreover, the IECG argued that, as a matter of equity, the T&D rate reduction should be granted to non-core or special contract customers as well as core customers.

Upon review of the written comments, the Commission scheduled a hearing on rate mitigation issues for March 2, 2001. The T&D rate cases for CMP and BHE, Dockets Nos. 97-580 and 97-596 respectively, were reopened for the purpose of holding the hearing and considering whether T&D rates should be lowered to mitigate

[1] We have incorporated the comments into this proceeding.

the impact of generation costs.[2] By scheduling the matter in T&D rate case dockets, the Commission adopted the general consensus of the commenters, and decided that price mitigation, if it were to occur at all, would be accomplished only by lowering T&D rates. The Commission also sought information from CMP and BHE on their projections for the amortization of the asset sale gain accounts and the recovery of their stranded costs.

Representatives from CMP, BHE, OPA, IECG, and IEPM participated at the hearing. Generally, the parties advocated positions that were consistent with their written comments. The IECG modified its request for T&D rate mitigation from 2¢/kWh to 1¢/kWh.

III. DECISION

Rate stability of electricity prices has long been a factor in our ratemaking decisions. Rate stability means the avoidance of substantial rate changes, particularly rate increases. *Investigation of Central Maine Power Company Stranded Costs, T&D Revenue Requirements and Rate Design,* Docket No. 97-580 at 114-115 (March 19, 1999). For purposes of implementing T&D rates for CMP effective with the beginning of retail access, we were guided by a "no-losers" principle. This principle meant that no customer should experience a rate increase with the implementation of T&D rates on March 1, 2000.[3] For purposes of deciding whether "rates" would increase on March 1, 2000, we considered both generation costs and T&D rates. Even though, effective March 1, 2000, generation service became non-utility, deregulated service, we used projected generation service costs to assure ourselves that overall rates would not increase on March 1, 2000. *CMP Phase II-B megacase Order,* Docket No. 97-580 (Feb. 24, 2000).

Even though generation costs are no longer regulated, it is clear that the post-March 1, 2001 generation price increases fall within a zone that can be described as "rate shock." If generation service were still regulated, we likely would have "phased in" increases of this magnitude. *See Investigation into Central Maine Power Company ratepayer complaints,* Docket No. 92-078 (Aug. 5, 1992) (Commission imposed 8% rate stability cap for rate design changes rolled back 4%); *Maine Public Service Company,*

[2] Because the price increases in MPS's service territory were significantly less, the Commission did not consider mitigation of MPS's rates.

[3] The sale of CMP's generation assets at substantially above book value, which created the asset sale gain account, gave the Commission considerable flexibility in designing T&D rates while implementing the" no-losers" principle.

Docket No. 84-80 (July 14, 1986) (Commission approved stipulation that phased the Seabrook investment into rates over 3 years).[4]

Moreover, the asset sale gain account that resulted from CMP's generation asset divestiture provides us the flexibility to consider generation price shock when we exercise our judgment to determine the schedule by which we amortize the account. Based upon the amortization implemented on March 1, 2000 and CMP's current projections, CMP forecasts level stranded cost recovery for ratepayers through 2005 and then a noticeable drop in 2006. We find it more reasonable to use a modest amount of available value now to reduce stranded cost recovery and T&D rates for the medium and large classes at this time, and reduce the anticipated rate reduction in 2006.[5]

In deciding to use the asset sale gain account to offset generation price increases, we also derive some comfort from the possibility that the price increases may result, at least in part, from the immaturity of the regional market and may thus be transitory. For example, congestion management and multi-settlement issues remain unsolved, useful demand-side response mechanisms are still lacking, and a generation information system is not yet in place. When these types of transition issues are resolved and uncertainty is reduced, generation prices may moderate. That possibly adds support to using the value from generation assets to smooth the generation price "bumps" while we move toward a workably competitive market.

In our judgment, a modest rate decrease of 0.8¢/kWh to T&D prices for customers within the medium and large non-residential standard offer customer classes over the period April 15, 2001 to February 28, 2002 is reasonable. April 15 is chosen for administrative and billing convenience. The reduction should first offset kWh charges, and then demand charges if necessary to realize the full benefit of the mitigation. Under no circumstances, however, should any T&D rate element become negative.

The 0.8¢/kWh reduction, which is approximately 10% of current generation costs, will provide a modest but nevertheless significant degree of price mitigation, without amortizing the gain account in a manner that will require future stranded cost-related rate increases. We find that an 0.8¢/kWh reduction achieves an equitable balance

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[4] We recognize that the goal of "rate stability" may in some circumstances conflict with the desire to ensure that consumers receive accurate "price signals." As long as consumers are still paying generation costs stranded from pre-restructuring days, however, they are arguably receiving an artificially inflated price signal. Against that backdrop, we do not see a danger that the action we take today to temporarily mitigate prices will "distort" consumer behavior in some economically undesirable way.

[5] The mitigation will cost $23.8 million, this has the effect of shortening the amortization of the asset sale gain account by less than 1 year from the presently anticipated 8 year remaining period.

between maintaining the gain account for future stranded cost recovery contingencies and using the account now to smooth the transition to competitive generation service.

We recognize that we are using the asset sale gain account at this time to benefit only medium and large customers, and reserve the right to consider that fact in our next stranded cost investigation when we decide class allocation issues. We will look for guidance and suggestions from the parties to that investigation regarding what the consequences, if any, should be of today's decision.

The 0.8¢/kWh T&D price mitigation will not be applied to those ratepayers on special rate contracts. Some T&D special contract customers pay T&D rates based on pre-existing "bundled" contract rates. Such customers pay the same total rate regardless of the cost of generation service because the T&D rate is reduced if generation prices rise. Thus, the T&D rates of those customers have already been (or will be) mitigated. Special contract customers that do not have pre-existing bundled contract rates will be affected by increased generation costs. However, these customers have bargained for reduced T&D rates in return for maintaining a level of contribution to T&D costs. Because these customers have had the benefit of lower T&D rates through contractual commitments,[6] we conclude that these customers should be held to the bargain they made with the utility. Moreover, many if not most of these contracts were negotiated based on the customers' assertions that, absent a special rate, they would find substitutes for all or part of the supply they received from CMP. We have no evidence here that the increase in electricity supply costs that these customers are now facing is not matched by increased costs for those substitutes; thus we cannot assume that, from a ratemaking perspective, further T&D price decreases (here in the form of mitigation) are warranted.[7]

Accordingly, we

O R D E R

That Central Maine power Company shall file rate schedules to implement the rate reduction as described in the body of this Order to be effective for service rendered on or after April 15, 2001.

[6] We note that the contract rates for most of these customers will remain lower than the mitigated core rate.

[7] If the substantial increases in generation prices would cause customers to reduce or eliminate service from CMP, we would expect CMP to seek to maximize contribution by reconsidering the contracted T&D rates.

Dated at Augusta, Maine, this 26th day of March, 2001.

BY ORDER OF THE COMMISSION

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Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. §9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Civil Procedure, Rule 73, et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.